of applying maximum torque to the driving wheels at any position; this capability was needed on rotary hoisting engines.

Single cylinder engines were used exclusively on rotary rigs until about 1918. They then continued in use for another 10 years in decreasing numbers, until they finally disappeared on rotary rigs during the late 1920's.

In 1918, the first two-cylinder rotary drilling engine came into the fields. It was, in fact, two 10 x 10 single cylinder engines mounted on a common base and with a common crank shaft and so connected and timed in valve motion that it would operate as a single twin engine. The fly wheels were eliminated, and a sprocket to drive the drawworks was placed on the crank shaft extending between the two engines. This makeshift arrangement operated quite satisfactorily, and especially designed twin engines built by several manufacturers were in the fields by 1920. The development of the steam rotary drilling engine, with illustrations, may be found in Chapter 9.

Steam powered rotary drilling rigs commenced their decline in use prior to the Second World War, in the late 1920's. They predominated in use throughout the war period and until about 1947-48, when the new post-war power rigs largely replaced them. Few steam engines have been built since that time though a few steam rigs were still used as late as 1965. Possibly a half dozen steam rotary rigs were reported running in October, 1970.

The rotary drawworks designed and used about 1915-16 remained in use with few changes until the late 1920's. A few new designs were brought out beginning in 1924, when the new E. M. Smith Company (Emsco) of Los Angeles built their three-post, two-shaft, three-speed, heavy duty, all steel drawworks with "equalized" brakes. Babbitt bearings, which had been in general use previously, were replaced by bronze bearings. It was still a "knock down" unit that had to be reassembled on each rigging up job. This machine set the stage for a new series of hoists of the same general type, until 1928 when the two-post, three-shaft, four-speed drawworks came out.

By about 1915, the major manufacturers of rotary drilling equipment, such as American Well and Prospecting Company, Lucey Manufacturing Company, the National Supply Company, Oil Well Supply Company, were all manufacturing their own designs of rotary drilling, fluid circulating pumps. Gardner-Denver, a manufacturer of mining equipment, had also come into the field. Others were to follow during the early 1920's.

The geologists, during the 1915-25 decade, had not yet developed their science to the point of locating exploratory wells on features where the objective oil producing zones were deeply buried. Consequently, wells were still relatively shallow, the deepest wells being about 5,000 ft. (see Table II in Chapter 33). Also, the requirement for speed in drilling wells had not yet developed. The pumps still remained of small capacity and low pressure. The small and large circulating pumps of 1915 were, respectively, 10 x 5-7/8 x 12 and 12 x 6¾ x 14. These were to remain the common pump sizes until about 1928, though one or two somewhat larger pumps had been built about 1926. The 14 x 7¼ x 14 pump was in use in California about 1926, and comparable pumps came into the Mid-Continent fields about the same time.

The great change in rotary machines took place about 1915 when the square kelly came into use, and grip rings were replaced by bushing. The types of kellys, or "grief stems" as then called and for some years thereafter, were to replace the round grief stems within the next few years and were to continue in use until the present time, and doubtlessly will remain for some

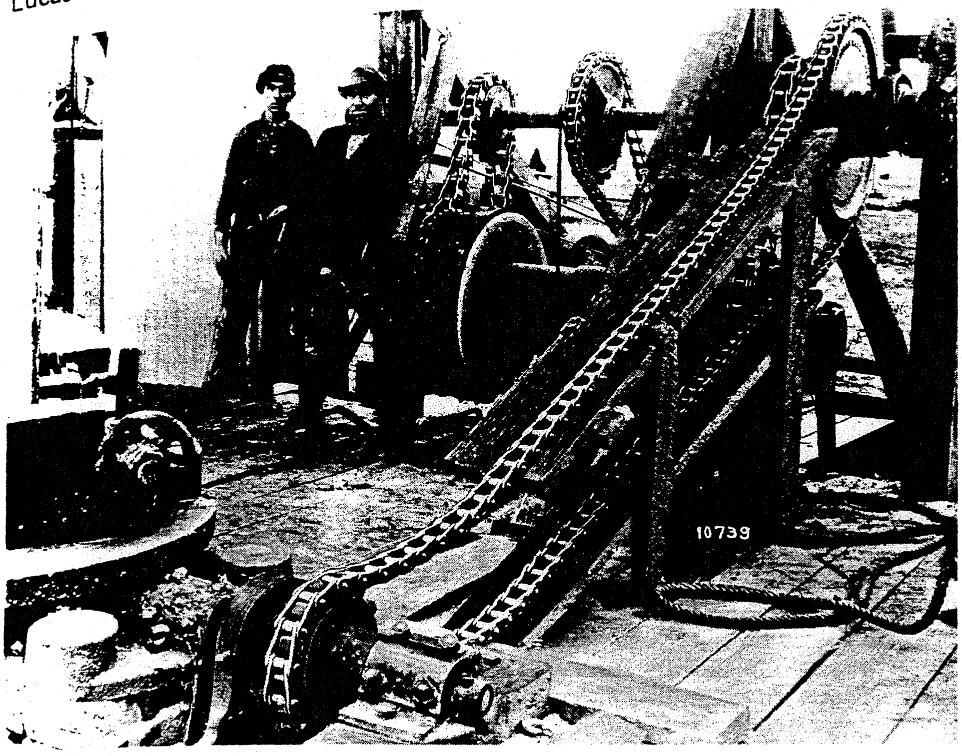

Figure 5.15. One of the last grip ring rotaries in service, 1921; pin and bar chain shown. (Courtesy of Link-Belt Co.)

years yet in the future. One of the last grip ring rotaries in service is illustrated in Figure 5.15.

Other changes or improvements in rotary tables during this 1915-28 period were the make and break table. This type table is illustrated and discussed in Chapter 17. Bearings were improved by replacing poured babbitt bearings with babbitt, brass or bronze replacable bushings. This was an important, time-saving change.

Other improvements during this 13-year period were in drill pipe and casing tongs and elevators. Drill pipe round trips were made with chain tongs at least as late as 1923, though both Dunn and Wilson tongs had been introduced prior to that time. Wilson side door elevators were introduced in 1916, and center-latch elevators were placed in service in 1922 (see Chapter 19). These tools were very effective in reducing round-trip time.

The Perkins two-plug method of cementing casing was introduced in California following the invention and development of the method from 1909 to 1911, when a patent was granted.

According to H. H. Rakershaw, an early drilling superintendent in Oklahoma, rotary wells drilled in 1918 and 1919 did not cement casing in the holes. By 1920, however, this same authority, in a letter to J. E. Brantly in 1955, stated that cementing casing strings had become common practice.

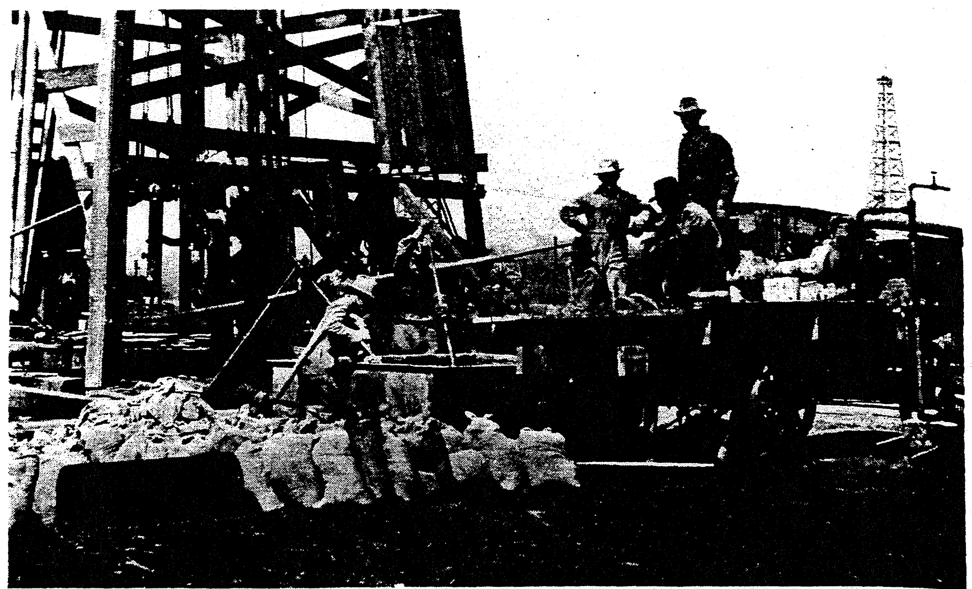

Figure 5.16. First Halliburton cement wagon, 1920.

In 1919, Earle Halliburton established a cementing service in Oklahoma comparable to the Perkins service in California, using the Perkins two-plug method. Since that time, the cementing of casing in oil wells has become a highly perfected and important art. The first Halliburton cementing wagon (horse drawn) is shown in Figure 5.16.

Casing hooks saw great improvement in the early part of the 1915-28 period. One great problem in coming out of the hole was that of holding the proper tension on the breaking joint to allow it to be backed out without injury to the threads, and for the pin to be hoisted out of the box, still without thread injury.

In 1917, the Wigle Spring Hook was invented and came into immediate, general service. The spring was designed to hold the proper tension on the pin in the box to allow it to be backed out without having to lift the stand of drill pipe and to move it upward out of the box to be set back with the stand.

This spring saved an appreciable amount of time in backing off and making up a stand of drill pipe. It improved considerably the efficiency of making round trips with the drill pipe. Damage to threads was materially decreased.

During this period, steels were improved, and the threading of joints was standardized. In fact, the API standardization committees commenced their sessions in 1924 and worked on standards for many or all items in the lists of drilling and well equipment that it was practicable to standardize. This was one of the great steps taken in the improvement of such items and in the efficiency of their use.

During this 1915-28 time interval, the demand for petroleum products was increasing rapidly. The first great influence promoting this increase was the First World War, when the allies "floated to victory on a sea of oil." Internal combustion engines and their use had expanded greatly during this period, and the use of heavy fuel oils in steam power plants, likewise, saw a great increase, especially on locomotives and steamships.

These increases in consumption created corresponding demands for new oil fields and more wells. Following a brief interlude of overproduction in 1920-22, coupled with a modest recession in the national economy, the demand for petroleum products influenced largely by internal combustion engines, especially in automobiles, commenced a long and still continuing period of increasing demand.

Drilling depths were increasing to bring in new and deeper producing horizons. The rotary rigs of 1915-18, which were those still in general use, had difficulty in meeting requirements. This brought out a few basic improvements, some of which have been mentioned, but they were not enough. Both manufacturers and operators realized the problems and recognized the fact that entirely new, improved and heavier drilling machinery was necessary to meet the requirements of the oil industry.

Beginning about 1926, the principal manufacturers of oil field machinery and tubular goods undertook a detailed study of the problem which resulted in new designs of an almost entirely new generation of oil field machinery and equipment in all of its types and varieties. An entirely new order of drilling machinery was on the drawing boards and beginning to be manufactured during the late 1920's. The exact time varied with the several manufacturers, but they were all to have new and greatly improved equipment in the fields by 1929-30. It was first built for and used in such fields as Oklahoma City, late Seminole development and deep Gulf Coast fields. They did not get into California until the early 1930's.

The discovery of the Signal Hill field in 1921 followed by the development of the Sante Fe Springs and Dominguez fields a short time later gave great impetus to the oil industry in California. These were relatively deep fields compared to older production and necessitated a reworking of various parts of the rig already discussed. There was not a great deal that could be done however. Consequently, the industry was forced to do the best that it could with the old equipment, some of which dated back to pre-1920 years. The new hooks, improved swivels, floor tools and improved drill pipe and improved tool joints helped.

During this same period, the early and middle 1920's, several important new rotary oil fields were discovered in the Mid-Continent and Gulf Coast. Among them were El Dorado and Smackover in Arkansas; Homer, Haynesville and Monroe in Louisiana; Pierce Junction, High Island, Powell and South Liberty in Texas. Also, several important new cable tool fields were discovered in Oklahoma.

The rotary rigs of Texas, Louisiana and Arkansas were of even lighter weight and generally older than those of California. There had not been much equipment purchased during the war, especially rotary rigs, and the brief post-war recession discouraged the purchase of new tools still further. Still another important deterrent to the purchase of new rotary tools was the fact that they had not yet been completely accepted for oil well drilling. However, they were beginning to be and within a very few years would begin to replace cable tools in all but old cable tool country and in hard rock drilling.

Other developments during the 1915-28 period were well head control devices, blowout preventers, well head spools and flanges and Christmas trees. The nature of the formation in the Los Angeles Basin area, the then meager knowledge of mud laden fluid and the meager knowledge of well drilling in general necessitated the running of several strings of casing. In Santa Fe Springs, Signal Hill and other comparable fields of the Basin, as many as seven strings of casing were run and left in the hole. Four to six strings in a well were common. Prior to these fields, the common control equipment on a well was a drilling gate valve and a simple Hosmer head blowout preventer.

Since the beginning of hydraulic rotary drilling, heavier and more powerful machinery allowed faster and deeper drilling, but the basic drilling practices had changed very little, if any. Improvements in drilling practices were related principally to drilling fluid, especially in greater volume and higher nozzle velocities on bottom. There were also considerable improvements in drilling bits in amount of hole made by one bit, decreasing unnecessary round trips to change bits.

APPENDIX 4-20

Appendix 4-20

Borehole Closure Test Well Demonstration (Clark et al., 1991)

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GULF COAST BOREHOLE CLOSURE TEST WELL ORANGEFIELD, TEXAS

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ABSTRACT

A borehole closure protocol for a Gulf Coast site near Orangefield, Texas was developed by Du Pont. These procedures were based largely upon recommendations provided by EPA Region 6 and created a borehole closure test to demonstrate that, under a worst case scenario, any artificial penetration will seal naturally. The borehole closure test successfully demonstrated natural sealing. Within one week of setting the screen, tubing and pressure transducers in the borehole, testing confirmed the absence of upward movement of fluid from the test sand. The documentation for the absence of upward movement included: 1) Schlumberger Water Flow Log* and 2) the absence of pressure response on the upper transducer located outside the tubing and inside the casing. Testing was conducted in accordance using specified procedures, with pressure testing conducted at even higher pressures to allow an added margin of confidence. The borehole closure test provides a significant additional margin of confidence that there will be no migration of hazardous constituents from the injection zone for as long as the waste remains hazardous.

INTRODUCTION

The borehole closure study was conducted to address concerns associated with the movement of injected fluids toward the Orange Salt Dome from the injection wells operated at the Du Pont Sabine River Works. The borehole closure test well (Orange Petroleum #35 Hagar) is located on the east bank of Cow Bayou on the eastern flank of Orange Salt Dome, east-southeast of the town of Orangefield, Texas (see Figure 1). The study was performed in response to EPA's request for additional information sufficient to demonstrate that, even assuming a worst-case basis that wastes might migrate across the faults at Orange Salt Dome, there would be no migration of hazardous constituents from the injection zone upward through artificial penetrations.

* Mark of Schlumberger

Previous studies (Johnston and Greene, 1979; Davis, 1986; Johnston and Knappe 1986; Clark et al., 1987) have reported qualitatively that wells drilled in unconsolidated (soft) rock, such as the Gulf Coastal Plain in Texas, experience natural borehole closure. This study was developed by Du Pont for a quantitative analysis on natural borehole closure and was based upon recommendations provided by EPA. The worst-case scenario developed for this study included: 1) a test interval within the injection zone consisting of a thin injection sand overlain by a thick, sand-free shale; 2) an open borehole with a diameter equal to the largest hole diameter expected to be encountered among the abandoned wells at Orange Salt Dome, 3) a mud program designed in accordance with drilling practices in general use at the time the abandoned boreholes in question were drilled (1919), and 4) actual testing with a 9.0 lb/gal brine since this is the worst-case condition for abandoned holes without plugging records. The test protocol provided that the test would be successful if, when a 100 psi pressure increase was applied, a Water Flow Log or oxygen activation (OA) log run at stations above the injection sand interval showed no upward channeling and an upper pressure transducer showed no pressure buildup.

The maximum calculated value for potential pressure increase at this site is <80 psi, which includes all possible sources of pressure increase: 1) maximum density contrast between natural formation fluid and the injected waste (0.75) and 2) a worst-case density drive if the plume extended from the plant to the dome (maximum dip 2400 feet). More likely, the long-term effect of buoyancy occurs where the plume has drifted from the plant to the dome and the number of feet of dip is considerably less, only 300 feet. In the latter case, the pressure due to buoyancy would be <10 psi. Thus, testing the borehole closure well to 100 psi increase is an extremely conservative approach.

If an artificial penetration had been abandoned with casing in place, the casing would corrode, thus 'exposing' whatever was in the borehole to the formation. This corrosion information was based on conservative data from Orange Salt Dome artificial penetration data and National Association of Corrosion Engineers data (Graver, 1985). Using a maximum casing wall thickness of 0.557 inch for 8 5/8-inch casing and a conservative corrosion rate of 20 mils per year, the casing would corrode in 28 years, which is long before waste reaches Orange Salt Dome in approximately 5,000 years. This value is consistent with casing corrosion data available from producing wells in the Orangefield area.

The geologic formations present at depths of 2000 feet - 8000 feet consist mainly of middle to upper Miocene sands, with lower Oligocene Anahuac Shale, and Frio sands at greater depth (see Figure 2). Tertiary sands and shales were deposited in a series of stacked progradational wedges, which dip and ultimately thicken toward the Gulf of Mexico. The lower Miocene Lagarto and the middle Miocene Oakville Formation are both characterized by very thick, fine to very fine grained sands, silts and shales deposited in a fluvial and deltaic environment. The regional geologic structural setting is one characteristic of salt tectonics, with salt dome intrusions, minor salt ridges and deep synclines. Orange Salt Dome is a piercement type salt dome (top of salt approximately 7000 feet) where considerable quantities of hydrocarbons have been produced since 1919.

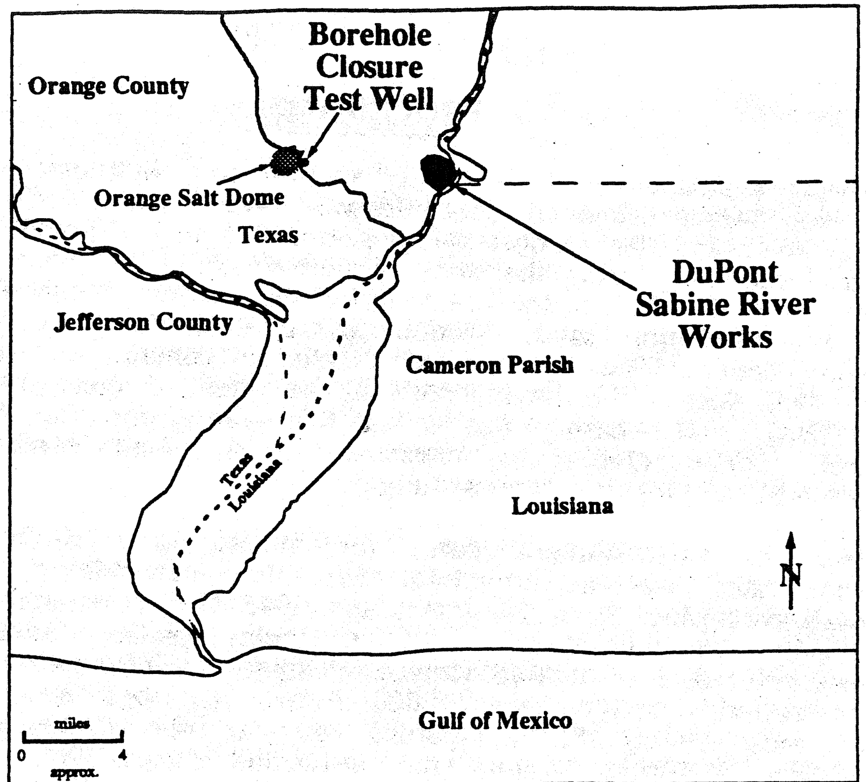

Figure 1 : Geographic Location Map of the Sabine River Works and the Borehole Closure Test Well

Period	*Epoch*	*Stage or Group*	*Formation*
QUATERNARY	HOLOCENE	Undifferentiated	
		12,000 YA	
QUATERNARY	PLEISTOCENE	Houston L. Wisconsin	Beaumont
		Wisconsin E. Wisconsin	
		Sangamon L. Illinoian	
		Pre-Sangamon E. Illinoian	Lissie
		Yarmouth Kansan	
		Aftonian Nebraskan	Willis
		2.8 MYA	
TERTIARY	PLIOCENE	Citronelle Group	Goliad
		5.2 MYA	
	MIOCENE	Fleming Group	Lagarto
			Oakville
		24 MYA	
	OLIGOCENE	Catahoula Group	Anahuac
		Vicksburg Group	Vicksburg
		37 MYA	

Figure 2: Stratigraphic Column for Eastern Gulf Coast. Adapted from Jackson and Galloway, 1984.

PROCEDURES

Following evaluation and analysis of the mudlog, lithology samples, openhole logs, and visual examination of sidewall cores obtained from the test well, several sand and shale zones were determined to be potential candidates for the test interval. Using the protocol developed by Du Pont with recommendations from the EPA, the criteria for test interval selection called for a thin clean injection sand, overlain by a thick sand-free shale within the injection zone. The injection sand selected contains 30 net feet of clean sand (2932 feet - 2962 feet) with 88 net feet of clean shale (2838 feet - 2926 feet). The casing was set at 2838 feet into the shale of the test interval. This graphic is presented in the well construction schematic using the electric log as a base (see Figure 3).

Analysis of two sidewall cores for particle size distribution from the injection sand was an important factor in determining the screen size. Sidewall core plugs from 2937 feet and 2945 feet were analyzed for porosity, permeability and lithology. Silt and clay particle analysis indicated a median grain size of 0.0046 inches. Using this information, the size of the screen assembly selected was 0.006 inches, the best gauge of screen that would most closely fit the particle size of the formation for a natural completion. Porosity within the test sand ranges from 29.6 to 31.8% (neutron-density log porosity ranges from 29 to 31%), with permeabilities on the order of 900 to 1400 millidarcies (md).

In order to satisfy a further worst case condition, Du Pont, at EPA's request investigated and evaluated electric logs of representative wells located within the confines of the 10,000-year waste plume. These artificial penetrations were evaluated for continuity of shale overlying the test sand. The shale of the test interval was demonstrated to be continuous and correlatable in its areal extent across the highest point of Orange Salt Dome. In addition, this test interval was at a shallow depth which minimized the geologic overburden pressures and the forces causing shale creep into the open wellbore.

BOREHOLE CLOSURE TESTING

OVERVIEW

Borehole closure testing started April 21, 1991 and was completed May 4, 1991. This sequence of borehole closure testing consisted of the following general steps:

Step 1

With drill bit and drill string still in hole, condition 9.7 lbs/gal mud in the open borehole. See Figure 4 for a schematic diagram depicting the mud circulation in the open borehole.

Step 2

Pulled drill string into casing and displaced mud with 9.1 lbs/gal filtered brine near the casing shoe to clean up the well bore casing and fluids prior to running the screen, transducers, and tubing assembly (see Figure 5).

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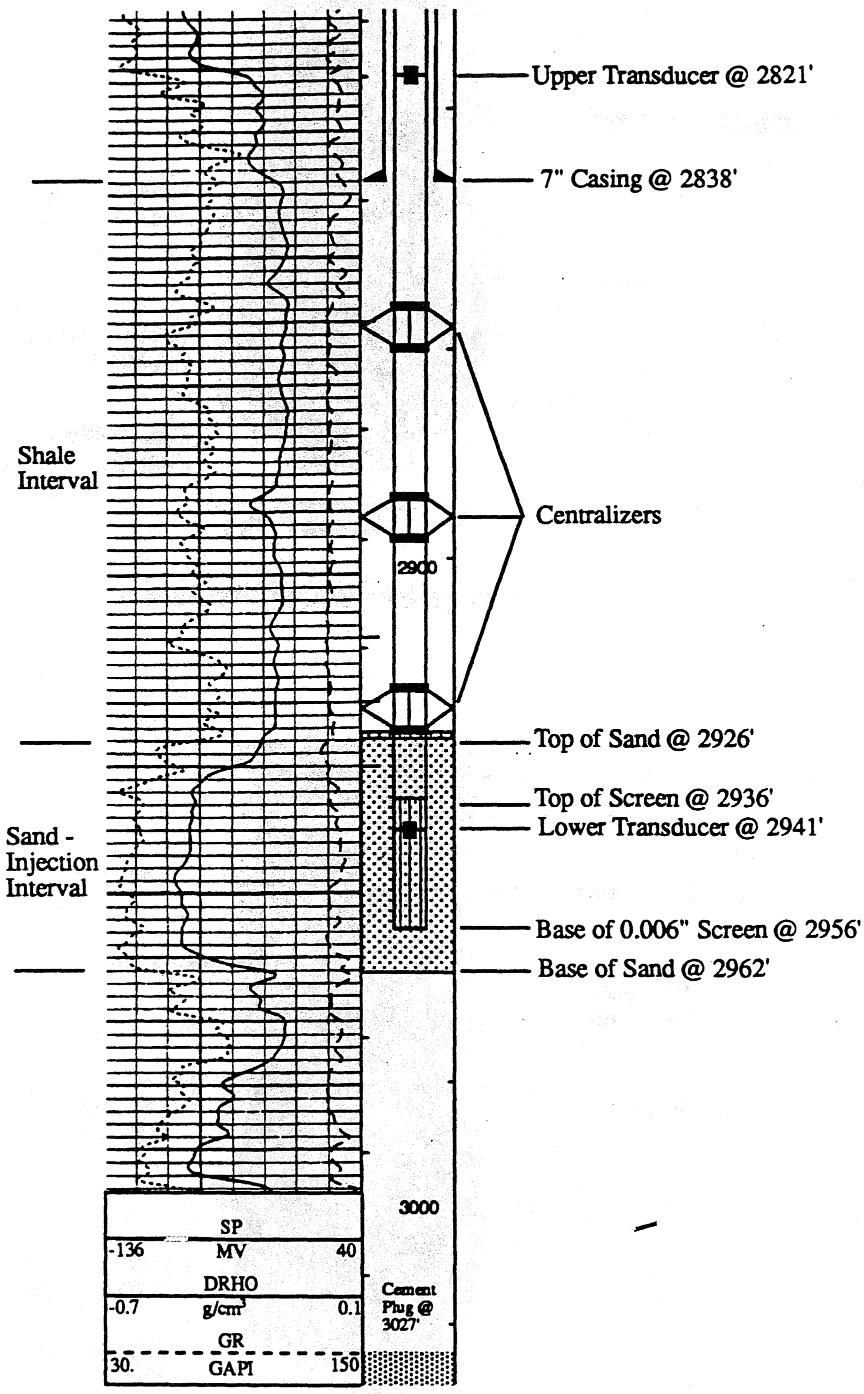

Figure 3: Borehole Closure Test Interval

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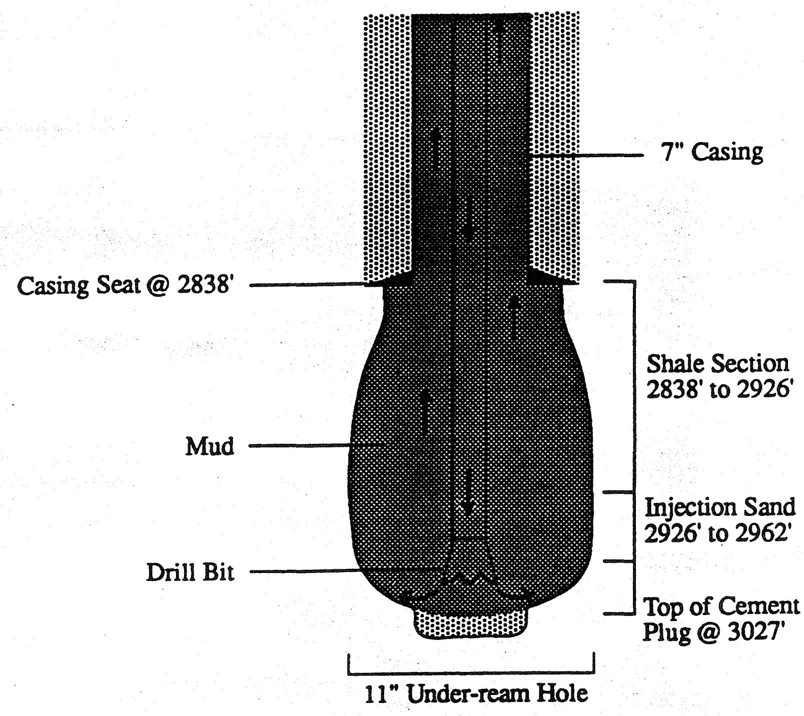

Figure 4: Mud Circulation

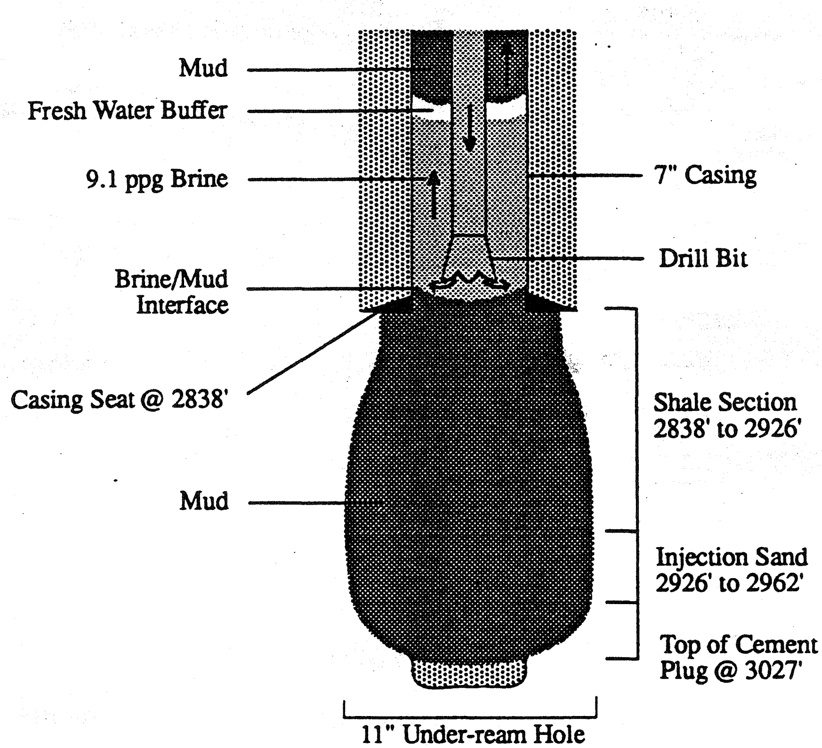

Figure 5: Mud Displacement with Brine Near Casing Shoe

Step 3

After the well bore casing was displaced with 9.1 lbs/gal filtered brine, the screen assembly, transducers, and tubing were placed near the bottom of the casing shoe. A transducer test was conducted to ensure that the electrical equipment was operating properly before running the screen assembly in the open borehole. In addition, filtered brine was pumped at various flow rates up to a maximum of 8.5 barrels per minute (bbl/min) to determine the friction loss in the screen section next to the lower transducer. See Figure 6, Transducer Test at Bottom of Casing.

Step 4

After the completion of the transducer test, the screen assembly was placed through the injection sand from 2936 feet - 2956 feet. Once this was completed, displacement of the remaining 9.7 lbs/gal mud with 9.1 lbs/gal filtered brine in the open borehole began immediately. See Figure 7, Screen Placement.

Step 5

A total of 401 barrels of 9.1 lbs/gal filtered brine was circulated to clean up the well bore. Mud returns from the open well bore occurred on the surface after pumping 85 barrels of brine down the injection tubing. The well bore discharge line started to clean up after 200 barrels of brine were pumped into the injection tubing. An additional 201 barrels of brine were pumped at decreasing flow rates until the discharge line indicated clean fluids in the return. See Figure 8, Brine Circulation After Mud Displacement.

Step 6

After displacement of the mud from the well bore with the 401 barrels of brine. the well was shut-in. See Figure 9, showing well shut-in with brine and recording falloff pressures.

Step 7

After waiting one week, during which time the formation pressure achieved equilibrium, a pre-injection slug test was conducted. The pre-injection slug test verified that the screen was open and that the injection formation was responding properly. Next, a Halliburton pump truck was placed on location along with a control valve to regulate the low flow rates anticipated for the pressure build-up testing. The initial injection testing indicated that borehole closure had occurred and Schlumberger was called out to run their Water Flow Log. Schlumberger performed the logging runs at various pressure rates and depths which indicated that there was no upward channeling of fluid and that borehole closure had indeed occurred. See Figure 10 for a schematic depicting Water Flow Log and Pressure Testing with Brine Injection.

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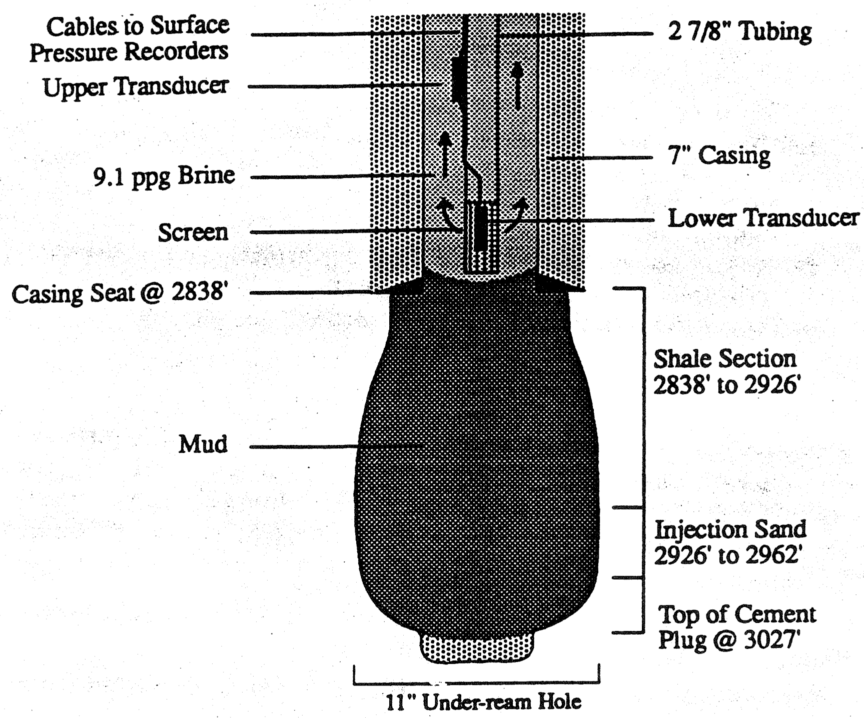

Figure 6: Transducer Test at Bottom of Casing

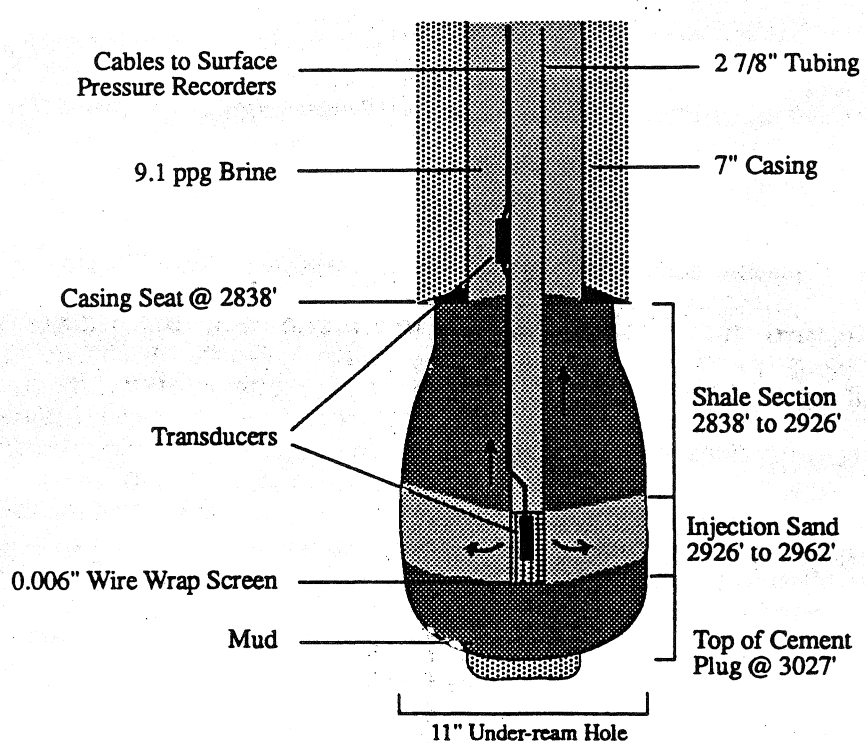

Figure 7: Screen Placement

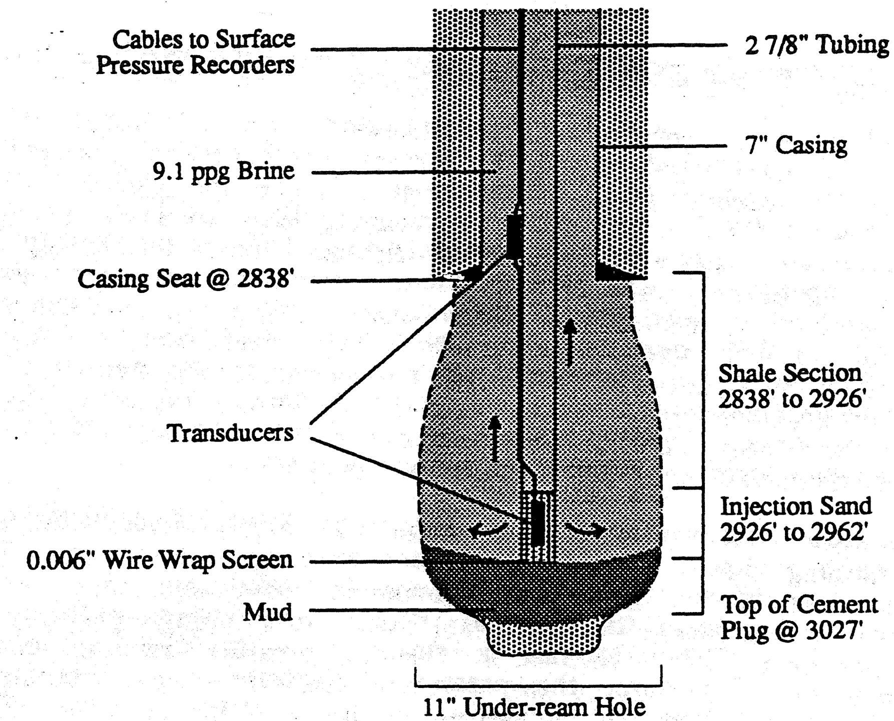

Figure 8: Brine Circulation After Mud Displacement

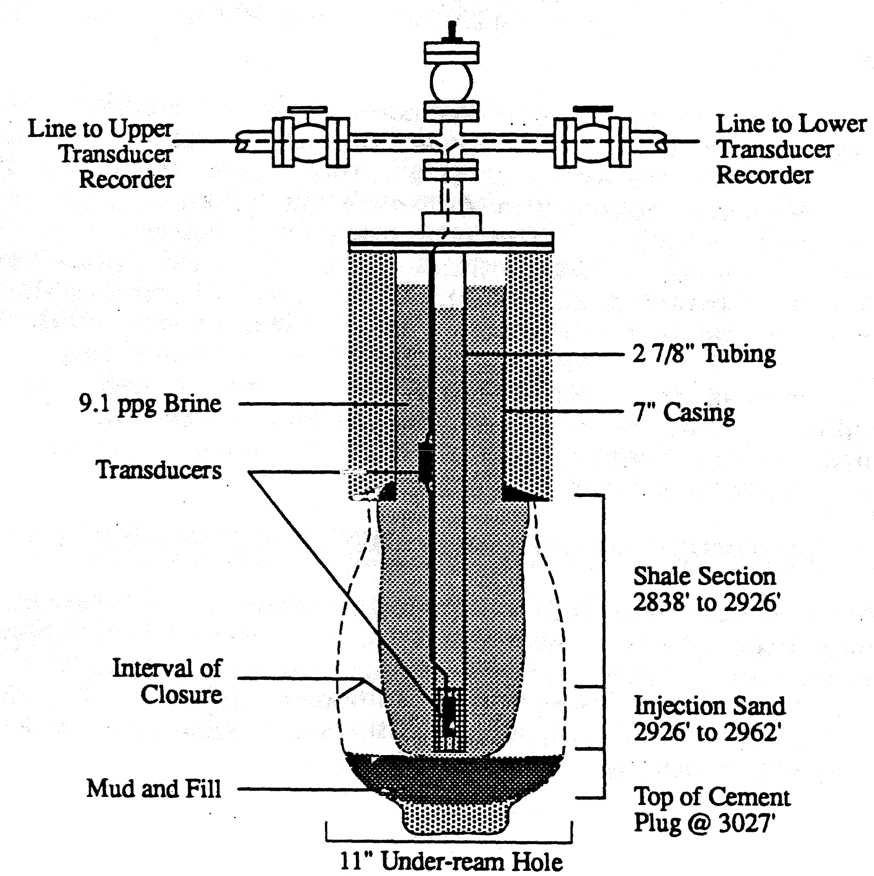

Figure 9: Shut Well In and Record Pressures

DETAILS FROM CONDITIONING HOLE TO MUD DISPLACEMENT

After the open borehole was conditioned with 9.7 lbs/gal mud the drill bit and pipe were tripped out of the open borehole and placed inside the casing above the casing shoe. Drilling mud inside the casing was displaced with 9.1 lbs/gal filtered brine near the casing shoe to limit mud invasion of the well screen. Once the mud was displaced from the casing and clear brine returns appeared on the surface, brine injection stopped, and the drill bit and pipe were tripped out of the casing. The lower transducer was installed inside the well screen, approximately four feet from the top of the screen openings. An upper transducer was attached to the outside of the 2 7/8 inch tubing approximately 120 feet above the lower transducer. Next, the screen, lower and upper pressure transducers, and the tubing assembly were lowered inside the well bore to a depth near the casing shoe.

A transducer test was conducted April 23, 1991, inside the well casing prior to running the screen assembly inside the open borehole. This tested both transducers under static and dynamic conditions and ensured that all electrical equipment (transducers) was functioning properly. The lower transducer at 2758 feet had a static pressure reading of 1305 psi (see Figure 11). Therefore, the pressure transducer was operating correctly by measuring the hydrostatic pressure of the 9.1 lbs/gal brine (0.052 x 2758 ft x 9.1 lbs/gal = 1305 psi). The upper transducer at 2638 feet (see Figure 12 also was operating properly by recording the static pressure of 1248 psi (0.052 x 2638 ft x 9.1 lbs/gal = 1248 psi). Another method verifying that the transducers were recording accurately is to state that (1305 psi - 1248 psi)/(0.052 x 9.1) = 120 feet, the distance that the transducers are separated.

A dynamic test was conducted after obtaining the static pressure measurements from the lower and upper transducers (see Figures 11 and 12). This test was conducted at several production rates (1.5 to 8.5 bbl/min) per EPA Region 6 requests to determine the pressure drop or friction loss across the screen assembly. The screen assembly consists of a wire-wrapped (0.006 inch) re-inforced tubing with a total of 120 holes per foot of screen (3/8 inch diameter per hole). This type of construction minimizes friction losses in the screen assembly. The dynamic test conducted near the casing shoe revealed that the pressure loss would be less than 12 psi for 2 bbl/min flow rate in the screen assembly. The upper transducer reflected a 10 psi buildup for this same time period showing that the 12 psi loss is not all attributed to friction loss inside the screen. The injection test itself was conducted at less than 0.5 bbl/min.

DETAILS FROM MUD DISPLACEMENT TO END OF TESTING

The pressures recorded from mud displacement to the end of testing for the lower and upper transducers are presented in Figures 13 and 14, respectively. Once the screen was properly placed, the 9.7 lbs/gal mud in the open borehole was displaced immediately with 9.1 lbs/gal filtered brine. Details for each of the major historical sequences comprising the borehole closure demonstration are described below.

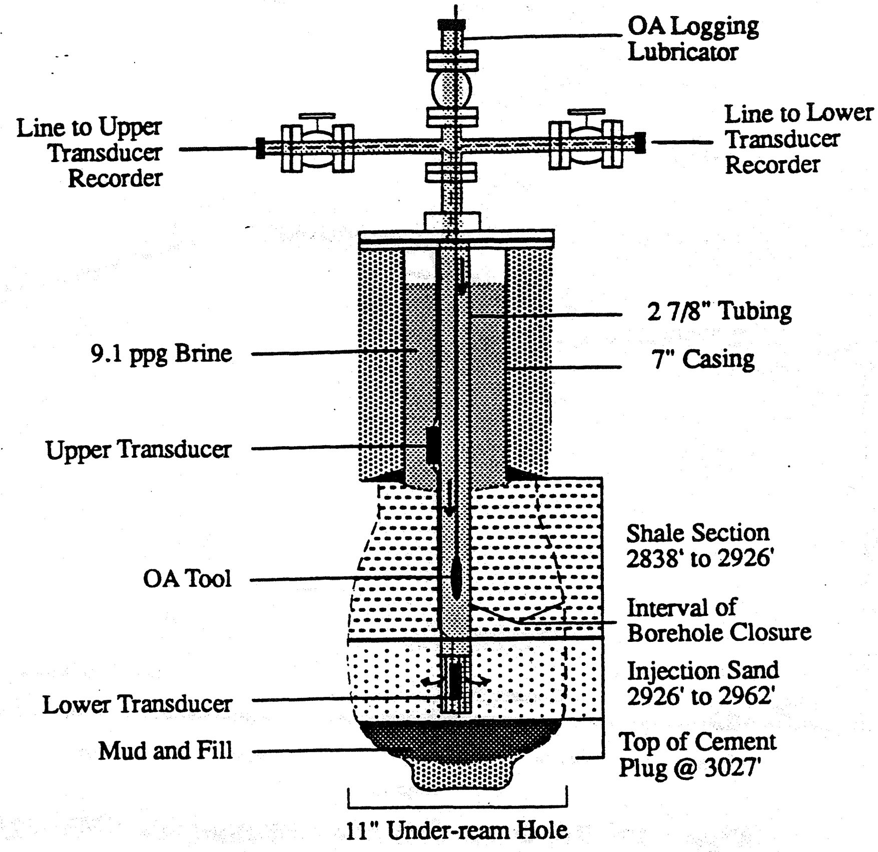

Figure 10: Water Flow Log and Pressure Testing with Brine Injection

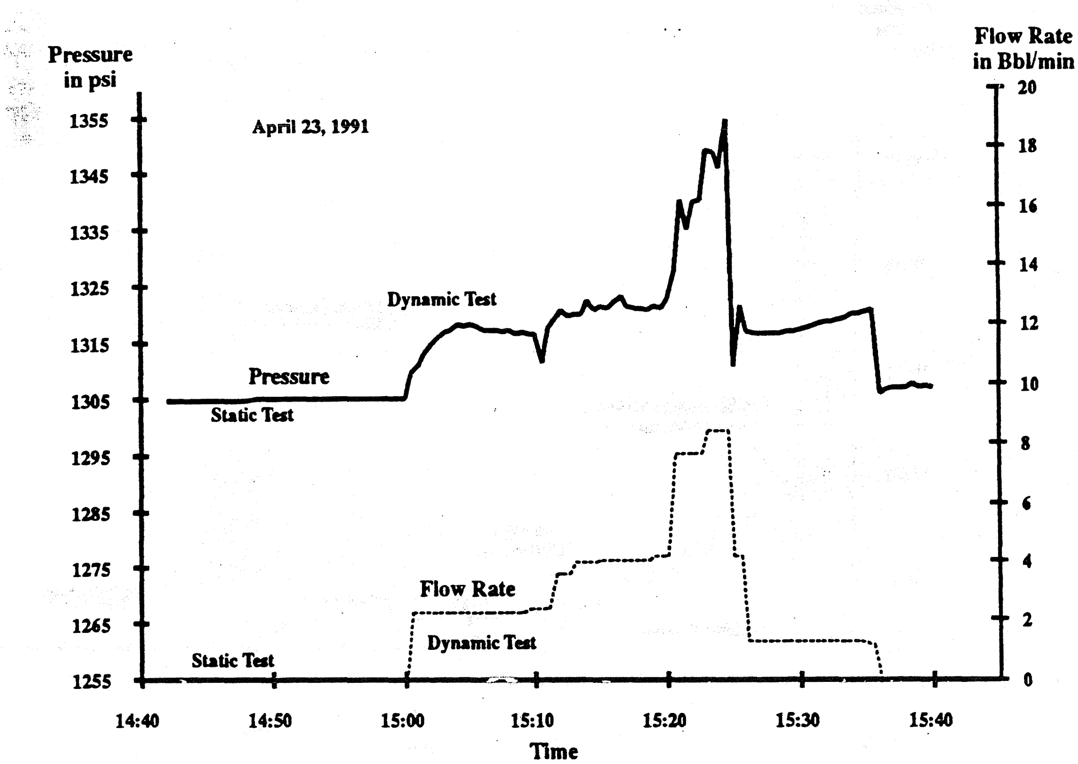

Figure 11: Transducer Test Near Casing Shoe With Lower Transducer at 2758 feet

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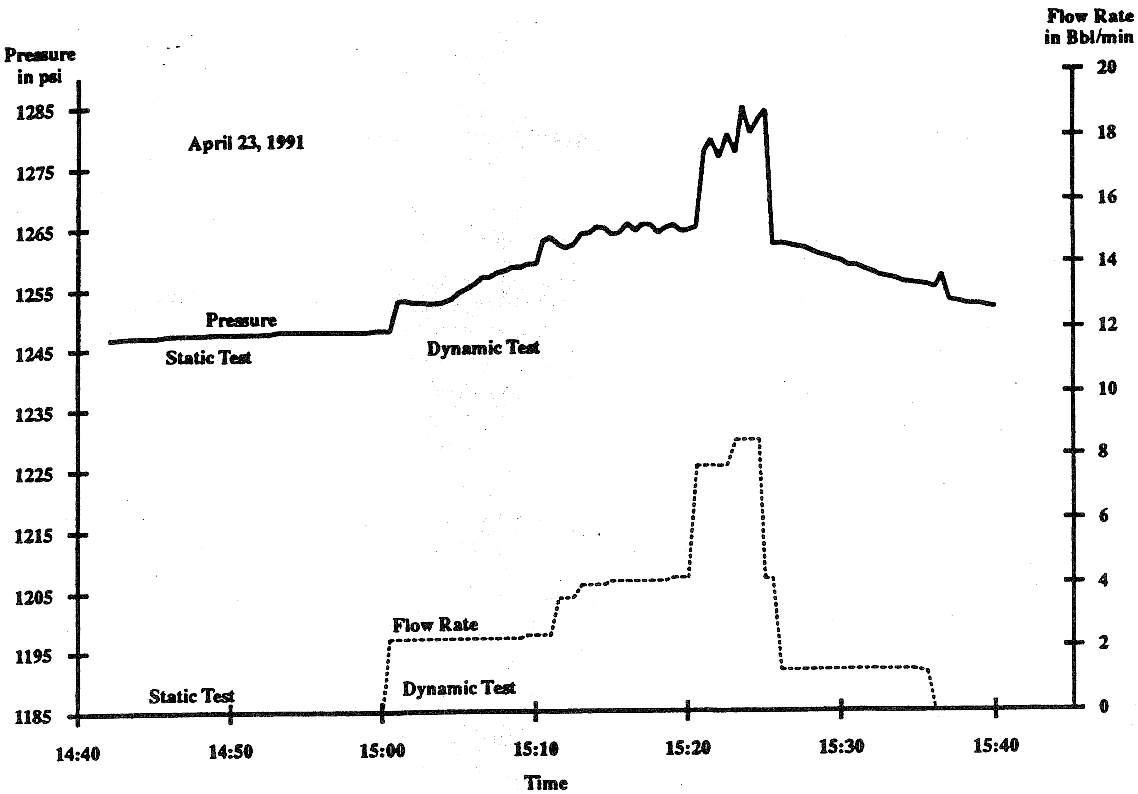

Figure 12: Transducer Test Near Casing Shoe With Upper Transducer at 2638 feet

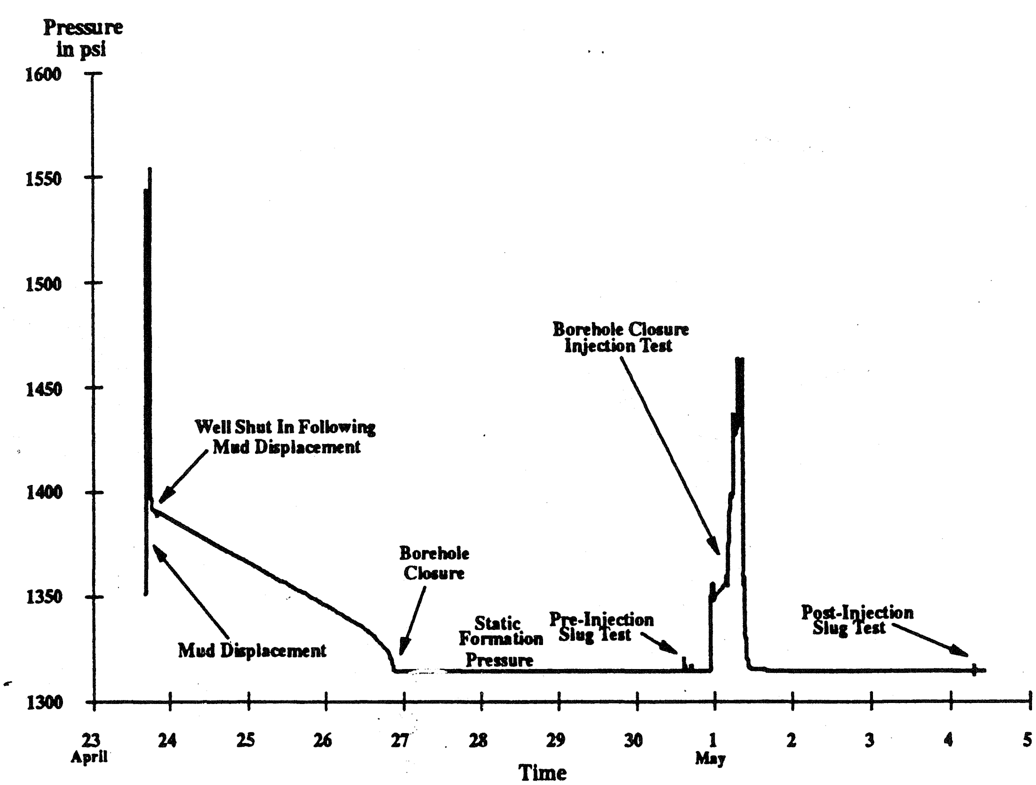

Figure 13: Lower Transducer Data From Mud Displacement to End of Testing

A total of 401 bbl of 9.1 lbs/gal filtered brine was pumped through the injection tubing with returns to the surface. Figure 15 shows that the mud displacement caused an increase in the pressure of the upper transducer at 2821 feet until mud was displaced from the well bore. After pumping 85 bbl of brine the drilling mud appeared on the surface and the discharge line was switched from the brine tank to the mud tank. The discharge rate near the end of the test was reduced gradually to prevent sudden well surges which could cause the well screen to fill with sand.

The final brine returns were clean with only minute traces of gumbo shale. After the mud displacement sequence, the well bore was shut-in and pressures were recorded. Recovery data (see Figure 16) show a slow pressure decline. Pressure data indicate that borehole closure occurred within 3 to 4 days after the well was shut-in following mud displacement. The screened interval or lower transducer reflects static formation pressure (1314 psi) within this time frame. Also, the upper transducer (inside the well casing) indicates a pressure-time slope change within this same time period. Only minor pressure changes occurred after this time period for the upper transducer, and this would be expected because the brine could still react with the shale below the casing shoe. Calculation of different fluid levels from the upper and lower transducers also show isolation of the two zones.

According to procedures agreed upon by Du Pont and EPA Region 6, it was Du Pont's decision to determine what duration to leave the well bore shut-in. Du Pont notifed EPA Region 6 after placement of the screen assembly that it would leave the well in a static condition for a time period of approximately one week before starting the injection test.

A pre-injection slug test (see Figure 17) consisting of two separate series of five slugs (each slug equaled 2.5 gallons of brine) was performed April 30, 1991, one week after shut in. The purpose of this test was threefold: 1) to determine if the screen was open and operating properly, 2) to determine the volume of water that might be needed to conduct a pressure buildup in the formation, and 3) to determine if there was a pressure response in the upper transducer. As shown in Figure 17, the fall-off curves in the lower transducer indicated that the screen was open (i.e., not filled with sand). There was no pressure response in the upper transducer from the slug testing, indicating that the two transducers were indeed isolated. Finally, the testing revealed that a pump truck would be required to control the low flow rate of brine injection. In addition, because the required flow rates could be lower than a truck could pump (less than 20 gpm), a valve was installed to regulate even lower flow rates. Halliburton computer flow monitoring and pumping services, Otis filters and brine fluids were ordered to the location for the borehole closure injection test.

Early testing data showed that the lower transducer was recording pressure buildup with no pressure increase observed in the upper transducer. The flow rate was increased slightly from 16 gpm to 22 gpm to obtain a 40 psi buildup. At this point, before reaching 50 psi of formation buildup, Schlumberger was called to run a Water Flow Log which would check for upward fluid channeling. Schlumberger was contacted for logging services at 23:30 on April 30, 1991. In order to conserve brine the flow rate was reduced to 16 gpm. The upper transducer continued to show no pressure change from injection, except for minor temperature anomalies associated with the

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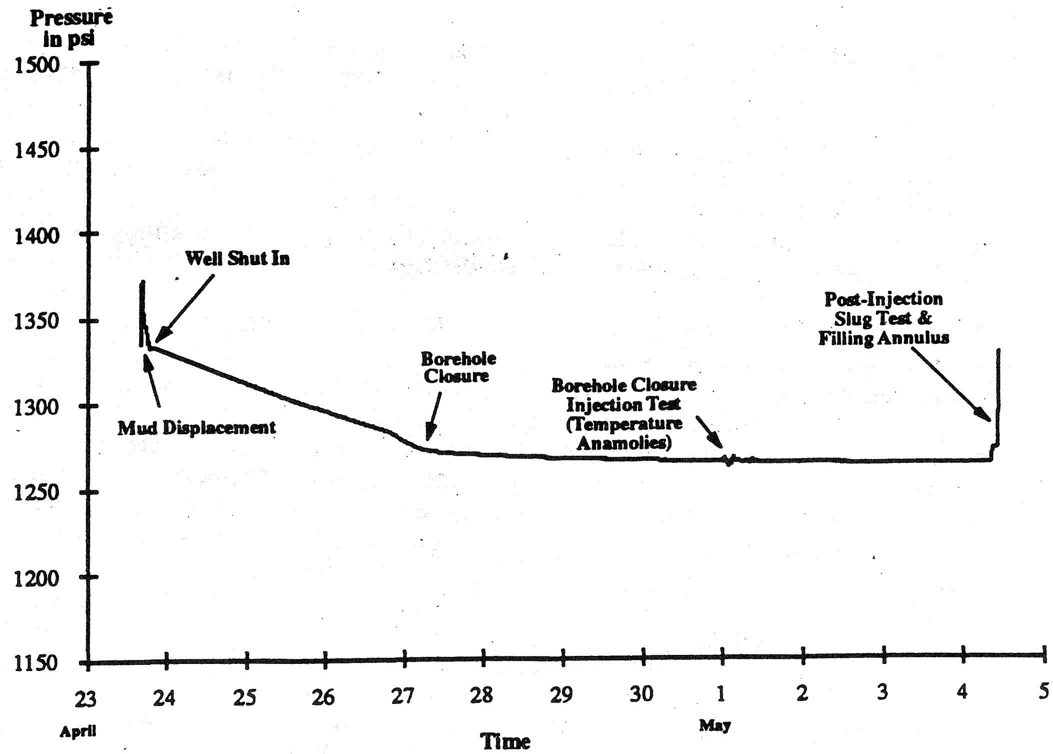

Figure 14: Upper Transducer Data from Mud Displacement to End of Testing

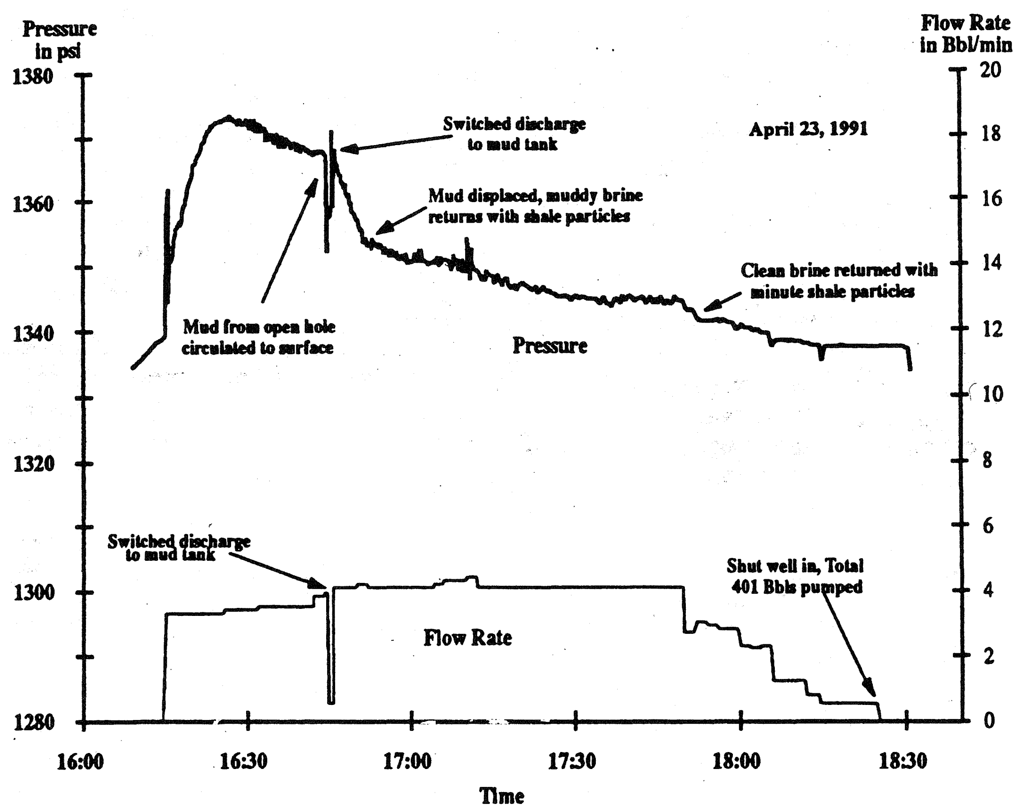

Figure 15: Mud Displacement With Upper Transducer at 2821 feet

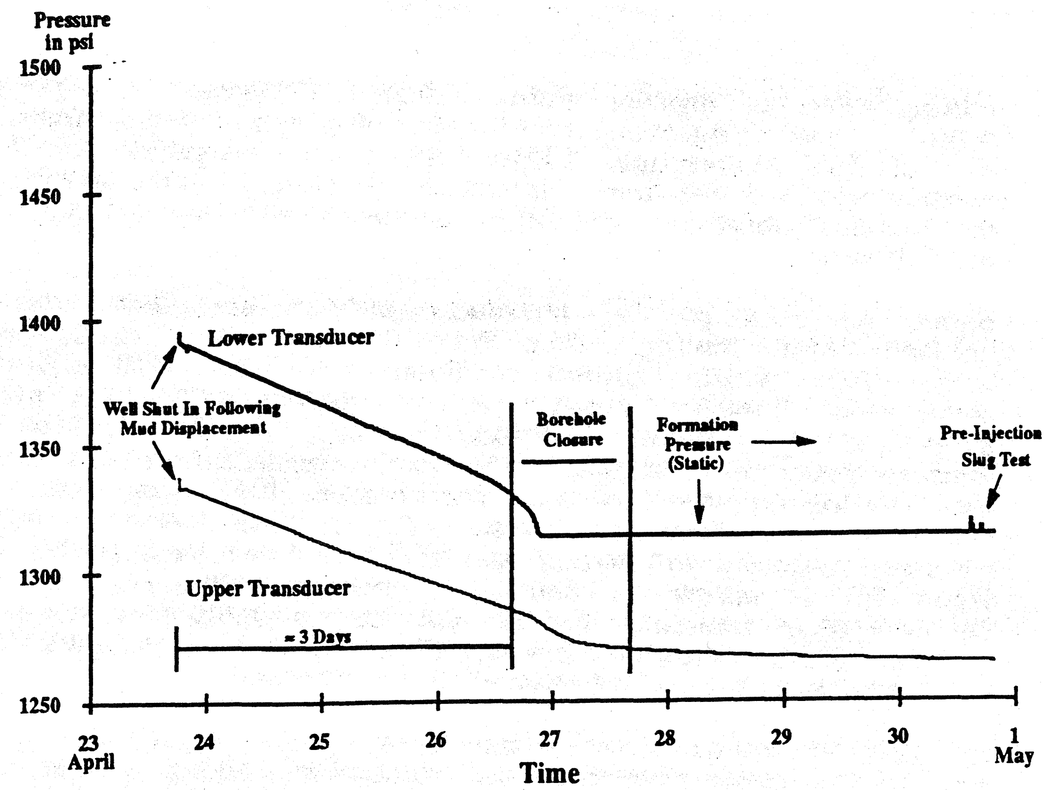

Figure 16: Recovery Following Mud Displacement

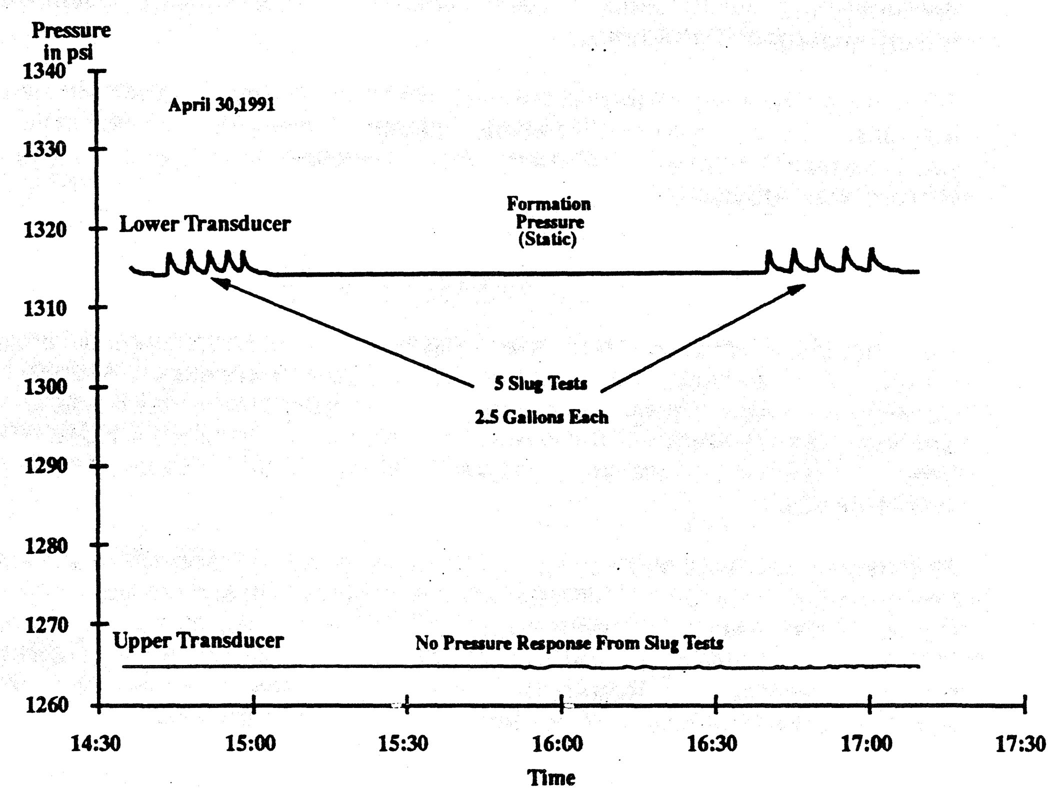

Figure 17: Pre-Injection Slug Test

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cooling effect of injection fluids. Figure 18 presents an overview of the borehole closure injection test for the upper and lower transducer and a plot of fluid temperature. Figure 19 is an enlargement of fluid injection temperatures and the upper transducer pressures. This graph demonstrates the minute temperature anomalies associated with the cooling of fluids in the well bore.

Figure 20 is a plot of transducer pressure and flow rates during the borehole closure testing. The Water Flow Log was conducted within the tubing under pressure control conditions at 90 psi, 110 psi, and 140 psi above static formation pressure and at stations within the overlying shale interval at approximately 25 feet, 50 feet, and 75 feet above the test injection sand. In an attempt to maintain constant formation pressure during each OA log run, the flow rates were reduced. Flow rates were increased to obtain the next formation pressure OA log run; however, the formation pressures continued to increase and the flow rates were further reduced (see Figure 20) to maintain a consistent formation pressure increase over static. Both the upper transducer and the OA logging indicate no upward channeling of fluid. The final run of the Water Flow Log showed no upward movement of fluids even as shallow as 25 feet above the injection sand.

Du Pont conducted a post-injection test prior to cutting the transducer lines to the surface recorders and pulling the tubing and screen assembly. The purpose of this test was to verify that the lower transducer was still working and that the upper transducer would respond to fluid placed in the annulus. Figure 21 shows that the upper transducer was working and that there was no bleed-off of pressure into the lower transducer. This was the case even when the annulus was filled to the surface with fluid. This also demonstrated well closure and sealing of the shale section between the injection sand and the casing.

EPA was not only interested in whether natural borehole closure occurred, but also if a rate of borehole closure could be quantified. During this test, natural borehole closure was demonstrated, and a rate of borehole closure was 'quantified'.

CONCLUSION

The borehole closure test was designed and constructed according to EPA criteria for a worst-case scenario. This worst-case scenario assumes that hazardous waste migrates across a non-sealing fault and encounters an artificial penetration of maximum borehole diameter filled with 9.0 lb/gal brine. The test interval selected was a thin sand overlain by a thick, sand-free shale.

The test sand was pressured up to the pressure specified and greater with no upward fluid flow or channeling detected during oxygen activation logging station, even with a minimum of 25 feet of shale. Recorded pressures indicate no channeling of fluid because of the pressure differential between the two sensors. Results of the test provide conclusive evidence that a borehole closes naturally, even under a worst-case scenario.

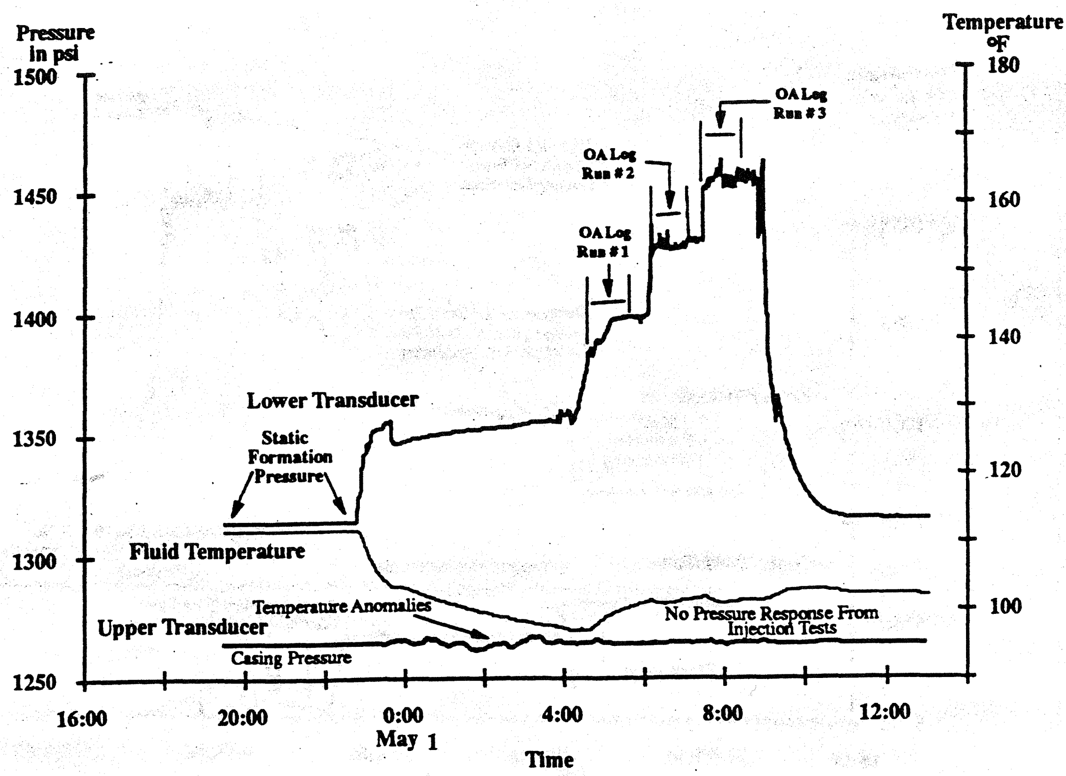

Figure 18: Borehole Closure Injection Test Upper and Lower Transducers- Pressure & Temperature

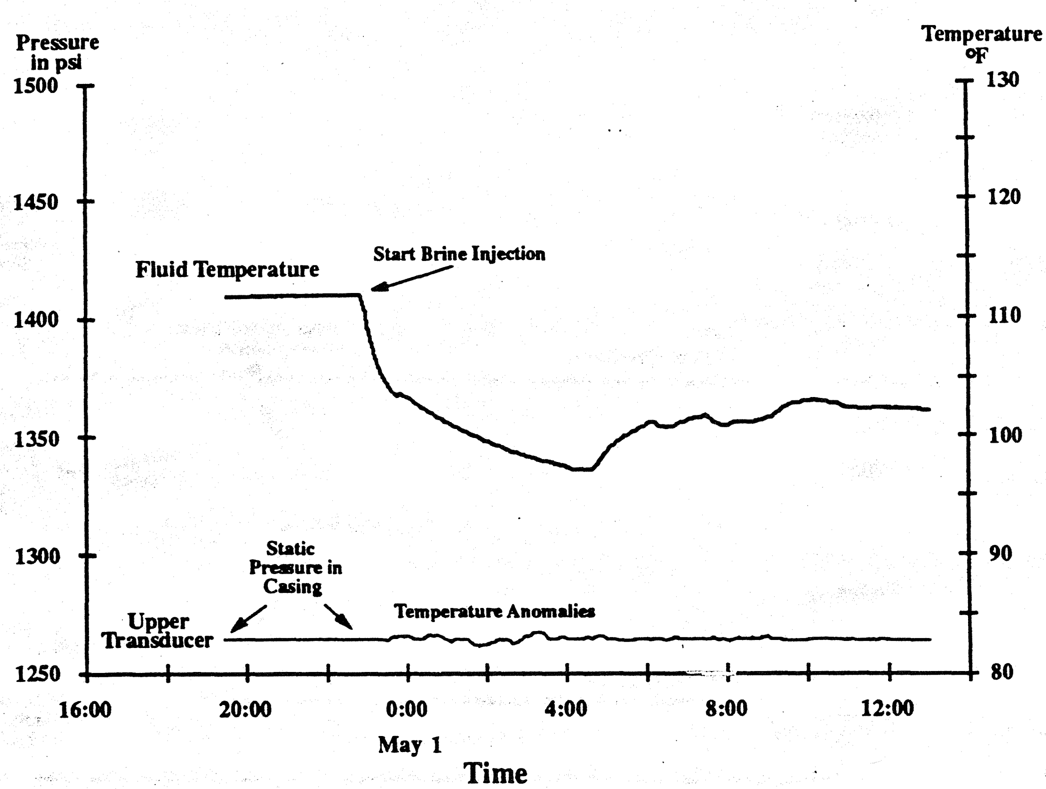

Figure 19: Borehole Closure Injection Test-Fluid Temperature Anomalies

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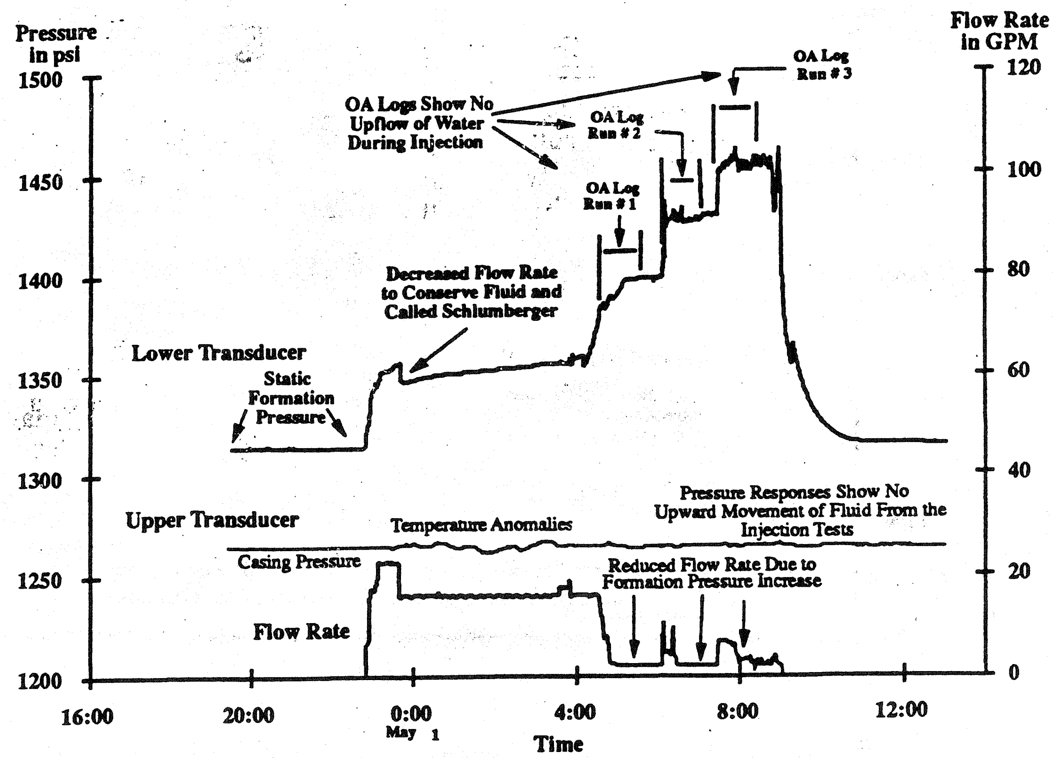

Figure 20: Borehole Closure Injection Test-Upper and Lower Transducer Pressure and Flow Rate

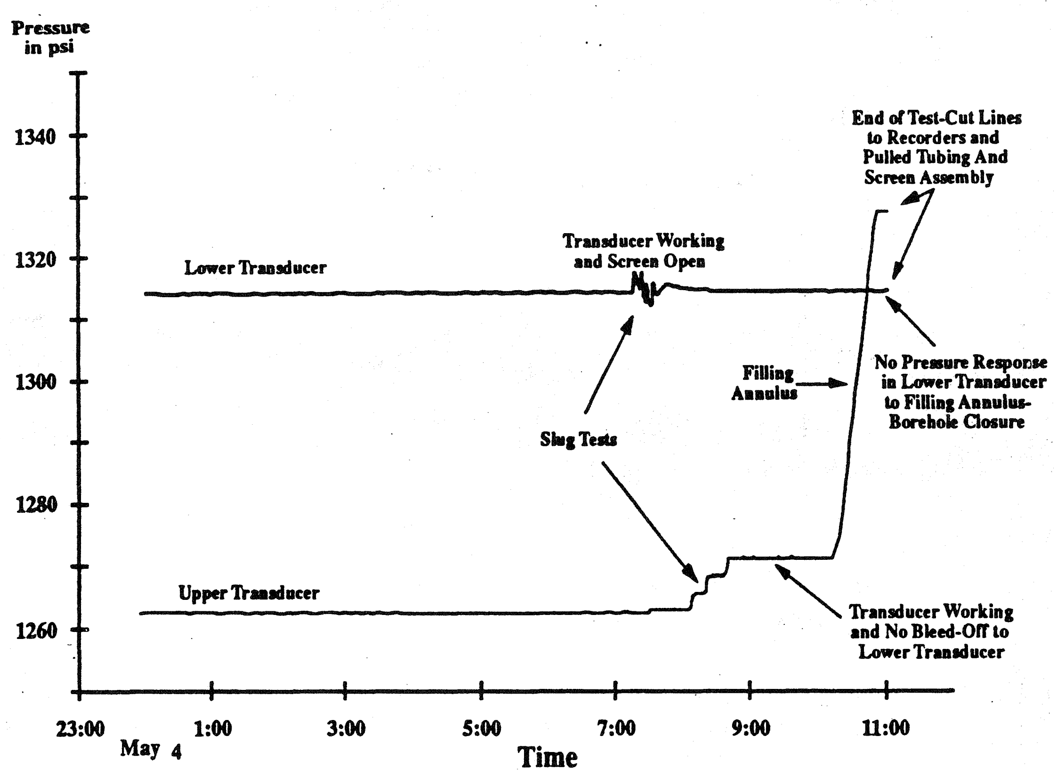

Figure 21: Post-Injection Transducer Testing

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